Supplemental Analysis of Trading and Scheduling Strategies Described in Enron Memos

Submitted to Federal Energy Regulatory Commission Staff
in Response to Final Report on Price Manipulation in The Western Market

by

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June 2003

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Introduction

This report summarizes additional analysis performed by the California Independent System Operator ("ISO"), Department of Market Analysis ("DMA") on the various trading and scheduling practices outlined in the Enron memos. The report supplements a variety of analyses previously provided by the ISO to Federal Energy Regulatory Commission ("Commission" or "FERC") Staff as part of its investigation of the Western Markets.[1] This updated analysis and report was prepared by the ISO in response to recommendations in the Commission Staff's Final Report on Price Manipulation in the Western Markets ("March 2003 Staff Report"),[2] and a subsequent request from Commission Staff for additional analysis that may be used in further investigations and disgorgement of profits from individual sellers, as recommended in the March 2003 Staff Report.[3]

The March 2003 Staff Report found that many trading strategies employed by Enron and other companies were undertaken in violation of market monitoring provisions of the Commission-approved tariffs of the ISO and the California Power Exchange ("PX"), and recommends that the Commission initiate proceedings to require companies to disgorge profits associated with these tariff violations.[4] The March 2003 Report also recommends that certain Market Participants identified in previous analyses submitted by the ISO to Commission Staff be directed to show cause why their behavior did not constitute violations of the ISO and PX tariffs.[5] Following the release of the March 2003 Staff Report, Commission Staff also requested assistance from the ISO in developing updated analyses and transaction-specific data for individual Market Participants whose behavior may constitute violations of the ISO and PX tariffs.

The results summarized in this report vary from results in the previous report cited in the March 2003 Staff report for a variety of reasons, as follows:

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[1] See, *Analysis of Trading and Scheduling Strategies Described in Enron Memos*, October 4, 2002; and *Addendum to October 4, 2002 Report on Analysis of Trading and Scheduling Strategies Described in Enron Memos: Revised Results for Analysis of Potential Circular Schedules* ("Death Star" Scheduling Strategy) January 17, 2003. Additional data and analyses were also provided in response to data requests issued in the recent 100-day discovery period of the California Refund Proceeding, Docket No. EL00-95, et al., and the Commission's investigation of on Price Manipulation in Western Markets: Fact-finding Investigation of Potential Manipulation of Electric and Natural Gas Prices, Docket No. PA02-2-00.

[2] *Final Report on Price Manipulation in Western Markets: Fact-finding Investigation of Potential Manipulation of Electric and Natural Gas Prices*, Docket No. PA02-2-00, March 2003 ("March 2003 Staff Report").

[3] As indicated in the ISO's initial report on the Enron strategies submitted on October 4, 2002, "the ISO stands ready to provide Commission Staff with additional documentation and analysis of these trading practices and to assist Staff with any aspect of its investigation."

[4] *March 2003 Staff Report* at ES-2.

[5] The *March 2003 Staff Report* appears to refer to the first report on Enron strategies submitted to Commission Staff and other legal/regulatory entities on a confidential basis on October 4, 2002 as the "January 6, 2003 Cal ISO Report". The January 6, 2003 date corresponds to the date that the ISO made the October 4, 2002 report public.

1) **Limited Time Frame**. Previous analyses by the ISO covered the time period from 1998 through 2002. However, the March 2003 Staff Report indicates that any disgorgement of profits would only cover activities during the period of January 1, 2000 through June 21, 2001, and that these disgorgements would be in addition to the refunds resulting from the California Refund Proceedings.[6] Therefore, the updated analysis summarized in this report covers the period of January 1, 2000 through June 21, 2001, and also provides subtotals for two periods: a *pre-refund* period from January 1 through October 1, 2000, and a *refund* period from October 2, 2000 through June 21, 2001.

2) **Additional Trading Practices**. Previous analyses by the ISO did not include a comprehensive analysis of the extent to which all Market Participants may have employed two of the major trading practices outlined in the Enron memos: Overscheduling of Load ("Inc'ing Load" or "Fat Boy"), and Ricochet (of "MW Laundering"). This report includes a more comprehensive analysis of these strategies.

3) **Additional Information Provided by Market Participants**. Several Market Participants have contacted the ISO and/or FERC to offer additional information, provide explanations, and/or correct data upon which previous analyses were based. This report incorporates those data corrections and other information to the extent that they could be verified by the ISO. For example, several Market Participants identified a limited number of Schedules or transactions that were miscoded with the incorrect identity of the Market Participant represented by the Schedule or transaction, or that were cut due to system conditions in the ISO or a neighboring control area. DMA has incorporated all of the verifiable changes and suggests that any further explanations by Market Participants be provided directly to the Commission in the context of any further investigation or show cause orders.

4) **Analytical Refinements/Corrections**. As noted in the ISO's previous reports, the ISO's analysis was intentionally designed to "cast a broad net", and identify all market activity that could be indicative of the strategies outlined in the Enron memos. Following release of the October 4 Report to regulatory and law enforcement entities, DMA has reviewed and refined its analysis, as reflected in this report.

In addition to the methodological descriptions and summary results presented in this report, DMA is providing detailed data files that identify the specific transactions, Schedules and Meter Data underlying this analysis. These data are being provided to allow further analysis and response to these results by Commission Staff as well as individual Market Participants.

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[6] *March 2003 Staff Report* at ES-2.

Finally, several important caveats regarding the scope of the analysis provided in this report should be noted.

- The ISO's analysis is limited to the specific strategies and methodologies outlined in the Enron memos as specifically described in this report. For example, the data and methodology employed in this report cannot identify the extent to which "Ricochet" or "MW Laundering" may have been employed by two or more participants. In those strategies, the Energy may have been exported and then re-imported under two different Schedule Coordinator identities, and the data would reflect no relationship between those transactions.

- The ISO's analysis is limited in two respects: it is based only on the data and other information available the ISO; and is constrained by the time and resources of DMA to devote to this analysis.

- While this report estimates potential revenues received as a result of different practices, it does not analyze the total market impacts of different practices, or other profits that individual Market Participants may receive as a result of the indirect and cumulative impact of these strategies on overall market prices and outcomes. For example, practices such as Ricochet and Overscheduling of Load represent ways to withhold supply from the forward markets (such as the PX Day-Ahead market) and to exercise market power in real time. In addition to raising prices in California's wholesale markets, these strategies would have also increased prices in future time periods by increasing the expectation of higher prices. The analyses in this report clearly do not incorporate the overall costs and profits associated with such broader market impacts. As noted in the ISO's filings in recent FERC proceedings, "it is virtually if not absolutely impossible to disentangle the effects of the various strategies engaged in by disparate sellers in order to assign discrete market effects and discrete ill-gotten gains to each instance of each seller's implementation of each strategy," since "the effects were simply too interwoven and too cumulative, both within an hour and over time."[7] .

- Finally, while DMA has sought to "screen out" transactions based on additional data and analysis, the summary results in this report are provided for all Market Participants, including those with a relatively small number of transactions and potential revenues from the strategies in the Enron memos. In general, the ISO believes that the volume of transactions and potential revenues identified for individual Market Participants in this report provides an indicator of the potential that these transactions represent intentional trading behavior such as described in the Enron memos (i.e. the smaller the volume of transactions and potential revenues identified for individual participants, the lower the likelihood that transactions represent intentional trading behavior such as that described in the Enron memos). In view of this, we continue to recommend that the results of the report be combined with other information collected through other investigative

[7] *Responsive Filing of the California Independent System Operator*, EL00-95-069, et al., March 20, 2003, page 8. http://www1.caiso.com/docs/2003/03/21/2003032109052124535.pdf

proceedings, and that some minimum threshold be applied in any further investigation of the activities.

I. Overscheduling Load ("Inc'ing Load", "Fat Boy")

The ISO's previous reports on the Enron strategies only included summary data on the degree of overscheduling of Load by Enron in 2000-2001. This report includes a more detailed analysis and summary of overscheduling of Load by all Market Participants in the January 2000 – June 2001 time period. The analysis includes several measures of the degree of overscheduling, ranging from total hours and MWs of overscheduling to the approximate amount of Imbalance Energy payments received from the ISO due to this overscheduling. However, it should be noted that, due to data and resource limitations, this additional analysis does not consider the market impacts of this strategy as a means of exercising market power by withholding Energy from the Day-Ahead Energy markets. As noted in the recent filings by the ISO, while the ISO believes the "Fat Boy" strategy had numerous detrimental impacts on the market and system reliability, the ISO believes these overall impacts are highly interwoven with other strategies for exercising market power and manipulating market outcomes. [8]

Methodology

The following sections provide a step-by-step summary of the methodology used to assess the degree of overscheduling by different Market Participants.

1. Provide and Format Load Schedule Data

The various final market Load Schedules (Day-Ahead Preferred, Day-Ahead Revised Preferred, and Hour-Ahead Preferred) in the *Load_sch* file for each hour and interval were combined to create a file with a single record for each hour and interval for each Schedule Coordinator at each Load point (or *Load ID*). For hours prior to ten-minute settlements (e.g. before September 1, 2000), this Load Schedule file was created on an hourly level. For the period after ten-minute settlements was implemented, hourly Load data were converted into a 10-minute interval format (i.e. each hourly Load Schedule value was divided by six, and the resulting value was used to create six records for each hour, representing the six ten-minute intervals within each hour). This conversion was done to allow Load Schedule data to be merged with Meter Data, and to calculate payments for uninstructed Energy based on 10-minute interval prices, as is done in the actual ISO settlement system.

2. Merge Load Schedules with Metered Load Data

The Load Schedule data file, created as described above, was then merged with metered Load readings in the Settlement system (*ss_measurements*, *ss_10min_measurements*), by Scheduling Coordinator, date, hour, Load ID, and, when applicable, 10-minute interval.[9] As noted above, for the time period prior to 10-minute

[8] See ISO filings referenced in Footnote 7.

[9] In the Load_sch table, the scheduling coordinator ID is the *sc_id* field, the date is the *opr_dt* field, the hour is the *opr_hr* field, the market type is the *mkt_type* field, the cong run type (e.g. preferred, revised

settlements (e.g. before September 1, 2000), matches were conducted at the hourly level; for the period after 10-minute settlement was implemented, Load Schedule and Meter Data were merged by hour and interval.

3. Aggregate Load Schedules and Meter Data by Congestion Zone

Load IDs were then matched to Congestion zone,[10] and then subsequently summed by Scheduling Coordinator, Congestion zone, date, hour, and interval,[11] to determine each Scheduling Coordinator's total hourly or interval-level zonal Schedule and meter readings. This level of aggregation was performed in order to allow transmission losses and Imbalance Energy charges/payments to be calculated for each Congestion zone based on zonal real time Energy prices in the same manner as the ISO settlement system.

Some special aggregations were made to account for the fact that during some periods Market Participants scheduled Demand under different Scheduling Coordinator IDs (SC_IDs) than those under which Load data were being metered, resulting in a mismatch of Load Schedules and corresponding Meter Data. These are summarized below.

(1) Data for January 19 and January 20, 2001 were excluded from the calculation for all Scheduling Coordinators due to scheduling confusion resulting from the shut down of the PX.

(2) From January 21, 2001 forward, Load Schedules, meter readings and transmission losses were summed for the following SC IDs: PXC3, PCG1, and PCGB. This was done to account for mismatches between the SC IDs for the Load Schedules and the corresponding metered Loads that occurred during the transition of Pacific Gas & Electric Company ("PG&E) from scheduling through the PX to being their own Scheduling Coordinator.

(3) From April 2001 forward, data were summed for the following SC IDs: PGAB and PGAE. This was done to account for mismatches between the SC IDs

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preferred run) is the *sch_class* field, and the Load ID is the *Load_id* field. In the *ss_measurements* and *ss_10min_measurements* table, the scheduling coordinator ID is the *short_name* field, the date is the *trade_int field*, the hour is *the trade_hr* field, and the Load ID is the *lctn_id* field. Additionally, in the *ss_10min_measurements* table, the interval is indicated in the *subhour_int* field. See the field description tables included with the source data files.

[10] The ZP-26 Congestion zone was not created until February 1, 2000, so Load IDs in ZP-26 prior to February 1, 2000 should be reassigned to the SP-15 Congestion zone.

[11] The PX, prior to its bankruptcy, used the PXC1 Scheduling Coordinator ID to schedule all Investor Owned Utility ("IOU") Load. Thus, it is difficult to separate out each IOU's Load from within all PXC1 Load. As a proxy, when the Scheduling Coordinator ID was PXC1, we identified the Utility Distribution Company ("UDC") area the Load point was within, and rewrote the sc_id as "PXC1 / "and the UDC area (e.g. PG&E, Southern California Edison Company ("SCE"), or San Diego Gas and Electric Company ("SDG&E")) to identify roughly which company's Load that would be.

for the Load Schedules and the corresponding metered Loads that resulted from a change in PG&E utility services' SC IDs during this period.

(4) Between April 6 and 30, 2001, data for two SC IDs (COTB and COTP) were summed to account for mismatches between the SC IDs for the Load Schedules and the corresponding meters resulting from a change in SC IDs for the California Oregon Transmission Project.

(5) Duke Energy Marketing and Trading Load Schedules for December 7, 2000, HE 14 through HE 22 were removed from the analysis due to information identified in their responsive testimony in EL00-95-075, indicating that Load was scheduled during these two hours at the request of, or at least with the approval of the ISO. Removal of these Schedules resulted in Duke Energy's elimination from the Load overscheduling results.

(6) Load Schedules at the GOLETA_2_V200LD Load point submitted through the PX were reassigned to Reliant Energy Services (NES1) due to information provided to the ISO that NES1 was scheduling Load at that point under the SC ID for the PX (PXC1).

4. Calculate Transmission Losses

One reason ISO Market Participants may overschedule Load by about 3% is to account for Generation produced to compensate for transmission losses that otherwise would be assessed to Generation resources as part of the ISO settlement process.[12] In order to incorporate expected Generation transmission losses into the analysis of Load scheduling, transmission losses during the ISO settlement process were estimated and incorporated into subsequent steps of this analysis.

In order to calculate zonal transmission losses for supply resources, Generation units and tie points were mapped into ISO Congestion zones (for interties, by ISO injection zone). We then obtained Final Hour-Ahead Generation Schedules from the *Generation_sch table* and interchange Schedules from the *I_interchange_sch table*.[13] We also obtained the calculated Generation Meter Multipliers (GMM) for each Generation unit, date, and hour, and the Tie Meter Multipliers (TMM) for each intertie, date, and hour.

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[12] For example, if an SC has exactly 100 MW of Load and generates exactly 100 MW of Generation, transmission losses associated with the SC's 100 MWs of Generation assessed during the ISO settlement process (which typically average about 3%) would typically result in the SC being charged for about 3 MW of negative uninstructed Energy (representing Imbalance Energy needed to compensate for 3% losses on Generation). The SC could avoid these charges by submitting a schedule for 103 MW of Load and then providing 103 MW of Generation. Under this scenario, the SC would have 100 MW of metered Demand and 100 MW of Generation (after losses), representing an uninstructed deviation of zero in the ISO's settlement process.

[13] For PXC1, import losses were not considered because it was impossible to determine which imports were intended to serve which utility's Load.

For Generation resources within the ISO control area, the meter multipliers were then applied in the following fashion. Two values were developed:

- The final Hour-Ahead Schedule (MW) without the GMM; and
- The final Hour-Ahead Schedule (MW) with the GMM applied, e.g. *FinMW * GMM*.

Transmission losses for these resources (*TLoss*) were then calculated based on the difference between these two values. As indicated in Step 7, in the event that estimated transmission losses were less than 3% using the above methodology, we assumed minimum transmission losses of 3% in order to avoid potential underestimation of transmission losses due to data errors.

For Interchange Schedules (representing imports and exports), the net interchange over a tie was calculated for each SC, date and hour by taking the sum of all imports and exports scheduled over each tie (i.e. based on final Hour-Ahead import/export Schedules). The TMM was then applied to this net import/export Schedule yielding two values:

- The final net Hour-Ahead interchange Schedule MW without the TMM; and
- If final net Hour-Ahead interchange Schedule MW was an import,[14] then the final net Hour-Ahead interchange Schedule MW with the TMM applied, e.g. *FinMW * TMM*; otherwise, just *FinMW*.

Losses for Demand associated with export from the ISO system (*TLoss*) were then calculated based on the difference between these two values.

After September 1, 2000, the two values were divided by six so that the values were uniformly distributed over six intervals.

Losses were then merged with zonal Load Schedules and meter readings by date, hour, interval, SC, and Congestion zone.

5. Calculate Imbalance Energy Charges/Payments for Deviations from Scheduled Load

Real time Energy prices were then merged into the set, and the following were calculated for each date, hour, interval (if applicable), SC, and Congestion zone:

For the pre-ten-minute settlement period (before September 1, 2000), an estimate of the Imbalance Energy price[15] was calculated:

$$((HA\text{-}Meter) - TLoss) * ZnEnergyPrc, \text{ if } \Delta(HA\text{-}Meter) \geq 0,$$

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[14] Note that according to the *I_interchange_sch* table's conventions, imports are a negative MW value.

[15] This calculation is only intended as an estimate of the uninstructed Energy settlement calculation; full accuracy requires calculation of metered Generation along with schedules, calculation of ramping Energy, etc., which were not replicated here.

Δ*(HA-Meter) * ZnEnergyPrc,* if Δ*(HA-Meter)* < 0,

where Δ *(HA-Meter)* is the difference between the final zonal Hour-Ahead Load Schedule and the metered Load quantity

TLoss is the zonal transmission loss for that scheduling coordinator

ZnEnergyPrc is the hourly zonal Imbalance Energy price.

For the post-ten-minute settlement period (after September 1, 2000), the price was calculated:

*(Δ(HA-Meter) – TLoss) * ZnDecPrc,* if Δ*(HA-Meter)* ≥ 0,

Δ*(HA-Meter) * ZnIncPrc,* if Δ(*HA-Meter)* < 0,

where

Δ*(HA-Meter)* is the difference between the final zonal Hour-Ahead Load Schedule and the metered Load quantity

TLoss is the zonal transmission loss for that scheduling coordinator

ZnIncPrc is the zonal incremental Imbalance Energy price for the specified interval, and

ZnDecPrc is the zonal decremental Imbalance Energy price for the specified interval.

6. Calculate Hourly Level Load Data for ISO System

Final Load Schedules, metered Load readings, transmission losses, and the estimated uninstructed deviation settlement amount for each Congestion zone were then summed for each Market Participant over the entire ISO system by date and hour.

7. Application of Potential Threshold for Hourly Overscheduling

A threshold value for overscheduling of Load, representing the level below which any overscheduled Load may be assumed to be due to forecast error and/or allowances for transmission losses, was calculated for each hour for each Market Participant based on the <u>maximum</u> of:

- 10% of the difference between the final Hour-ahead Load Schedule and actual metered Demand, plus estimates of transmission losses (see Step 4 above);
- 13% of final Hour-Ahead Load scheduled[16]; or
- 25 MW

The minimum absolute value of 25 MW used in setting the threshold represents the minimum block that is most commonly used to trade and schedule Energy. This was included as an alternative minimum threshold to account for a scenario in which a Market Participant may have "rounded up" Demand Schedules as much as 25 MW to balance Energy that needed to be procured in minimum increments of 25 MW.

8. Calculation of Different Measures of Overscheduling

The final stage of this analysis involved the calculation of a variety of different measures of overscheduling by individual participants based on hourly results. These measures include the following:

1. Hours of Load Overscheduling (with and without threshold level)
2. Average MWs of Load overscheduled during hours of overscheduling (with and without threshold level)
3. Average Load overscheduled as a percentage of total Load during hours of overscheduling (with and without threshold level)
4. Total payments for overscheduled Load during hours of overscheduling (with and without threshold level).[17]

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[16] As previously noted, a value of 13% (representing 10% plus a minimum of 3% transmission losses) was used in the event that calculated transmission losses were less than 3%. This was included to avoid underestimation of transmission losses in the event of any data errors

[17] For this analysis, if a Market Participant's total aggregate system-level Load deviation was less than zero (e.g. on a system-level, if a Scheduling Coordinator was a buyer in the Imbalance Energy market), then the estimated uninstructed deviation settlement was set at zero. This reflects the fact that during hourly settlement before September 1, 2000, these Scheduling Coordinators would actually have paid for Energy at the Imbalance Energy price. After September 1, 2000, since the decremental Energy price was typically less than the incremental Energy price if Energy was decremented in a zone, Scheduling Coordinators would also have paid for Energy at some price between the maximum incremental Energy price and the minimum decremental Energy price. In any event, these Scheduling Coordinators would be excluded from the threshold filter, since on a system level, they underscheduled.

Results

Results of this analysis are summarized in Tables 1 through 3.

Table 1. Overscheduling of Load (pre-refund Period)

ID	Total Number of Hours	Number of Hours where Over Threshold	Pct. Hours Over Threshold	Average Metered Load when Over Threshold	Average MW Overscheduled when Over Threshold	Average Load Deviation % when Over Threshold	Sum of MW Overscheduled when Over Threshold	Total Estimated Uninstr. Energy Payment when Over Threshold
EPMI	6,599	4,324	66%	765	343	45%	1,483,090	$215,829,088
PWRX	5,055	2,590	51%	157	256	162%	661,999	$118,717,742
PETP	2,353	2,046	87%		244		499,951	$73,570,487
SCEM	3,726	3,097	83%		154		477,015	$69,454,119
APX1	6,599	3,674	56%	213	142	67%	520,005	$61,198,406
SETC	6,576	3,288	50%	25	144	583%	474,001	$60,257,635
HFET	1,536	1,437	94%		222		318,894	$49,008,313
PGAE *	6,599	1,191	18%	1,017	215	21%	256,534	$25,601,170
CRLP	3,623	2,225	61%	42	81	193%	180,817	$21,200,264
CAPP	6,247	2,158	35%	1	125	16030%	270,478	$13,925,705
ECH1	6,599	1,446	22%	44	72	163%	104,572	$10,995,035
NCPA	6,502	1,087	17%	38	57	150%	61,918	$8,499,350
RVSD	6,599	1,462	22%	230	55	24%	79,729	$7,499,638
APS1	6,599	1,086	16%	134	58	43%	62,800	$7,386,903
NES1	6,599	766	12%	0	92	27588%	70,337	$6,353,060
NEI1	5,759	780	14%	563	116	21%	90,286	$5,620,760
PGES	4,008	1,337	33%	399	128	32%	170,892	$5,477,717
SRP1	6,599	820	12%	432	89	21%	72,961	$5,314,333
ANHM	6,599	677	10%	316	73	23%	49,409	$4,452,106
PXC1 / SDGE *	6,599	72	1%	1,852	300	16%	21,612	$2,313,812
VERN	6,599	131	2%	146	50	34%	6,555	$1,781,832
SCE1	6,599	87	1%	5	162	3397%	14,098	$1,744,610
WESC	6,570	624	9%	0	70	15888%	43,697	$1,646,287
PASA	6,599	340	5%	169	36	21%	12,226	$1,165,754
AZUA	6,599	150	2%	39	30	75%	4,468	$747,416
PXC1 / SCE *	6,599	35	1%	6,602	1,007	15%	35,246	$724,175
LGE1	3,648	208	6%	527	104	20%	21,698	$647,585
COTP	6,598	3	0%		998		2,993	$492,247
IEPI	6,599	173	3%	188	33	17%	5,676	$149,747
PXC1 / PGAE *	6,599	23	0%	7,134	1,221	17%	28,085	$134,307
WAMP	6,599	47	1%	105	33	32%	1,558	$124,732
PAC1	6,599	7	0%	32	26	80%	181	$25,358
IPC1	6,599	23	0%	15	31	209%	712	$22,468
SCL1	6,599	1	0%	4	25	696%	25	$756

* Results for PGAE and SCE1 include Schedules submitted by other entities through PG&E and SCE as their Schedule Coordinator, respectively. The ISO does not have data to clearly identify which Schedules/Meter Data correspond to Market Participants other then PG&E and SCE.

Similarly, results for the PX (PXC1) were disaggregated by the utility distribution system in which Load IDs were located (PG&E, SCE or SDGE). Therefore, these results include Schedules/metering data for these utilities as well as other entities.

Table 2. Overscheduling of Load (Refund Period)

ID	Total Number of Hours	Number of Hours where Over Threshold	Pct. Hours Over Threshold	Average Metered Load when Over Threshold	Average MW Overscheduled when Over Threshold	Average Load Deviation % when Over Threshold	Sum of MW Overscheduled when Over Threshold	Total Estimated Uninstr. Energy Payment when Over Threshold
EPMI	6,240	1,692	27%	880	461	52%	779,460	$117,198,791
PWRX	2,809	1,379	49%	169	455	269%	628,049	$90,530,475
SCEM	2,133	1,565	73%		256		400,403	$52,640,866
PETP	1,621	1,410	87%		257		363,009	$50,162,622
SETC	4,481	1,364	30%		250		340,655	$49,186,574
APX1	6,240	1,596	26%	148	207	140%	329,976	$42,937,678
HFET	857	856	100%		226		193,667	$27,852,560
PGAB / PGAE *	4,055	839	21%	1,352	299	22%	250,731	$16,031,412
ECH1	6,240	1,004	16%	46	88	191%	88,131	$12,486,729
PXC5	80	80	100%		1,125		89,999	$12,267,851
CRLP	6,240	884	14%	33	79	238%	70,010	$9,049,845
PGAE	2,185	177	8%	1,190	211	18%	37,286	$7,622,510
NCPA	6,240	752	12%	34	64	187%	48,022	$7,416,476
PXC1 / SDGE *	2,881	203	7%	1,443	259	18%	52,507	$5,145,092
NES1	6,240	462	7%	0	87	8485825%	39,978	$4,794,661
RVSD	6,240	1,195	19%	175	39	22%	46,172	$3,143,020
SRP1	5,017	226	5%	456	95	21%	21,411	$3,076,979
PXC3 / PCG1 *	3,623	153	4%	7,785	1,341	17%	205,195	$2,665,302
ANHM	6,240	583	9%	262	59	23%	34,461	$2,142,590
PSE1	48	48	100%		150		7,200	$1,705,367
NEI1	6,240	264	4%	151	40	26%	10,481	$1,657,619
WAMP	6,240	126	2%	117	33	28%	4,164	$904,080
SDG3	3,359	36	1%	1,568	270	17%	9,729	$670,814
PASA	6,240	54	1%	126	44	35%	2,373	$373,685
PXC1 / SCE *	4,474	9	0%	6,743	929	14%	8,358	$358,550
PAC1	3,123	25	1%	26	91	348%	2,267	$324,679
APS1	6,240	75	1%	84	30	35%	2,227	$280,344
SEL1	6,240	49	1%	33	30	92%	1,491	$161,648
VERN	6,240	77	1%	113	37	33%	2,879	$153,894
WESC	5,911	68	1%		42		2,878	$126,036
CAPP	5,856	28	0%	13	27	213%	747	$111,231
APX3	3,089	19	1%	47	52	109%	986	$88,712
EPPS	3	2	67%		68		135	$9,497
AZUA	6,240	1	0%	9	29	308%	29	$2,979
IPC1	6,240	2	0%	9	26	279%	52	$297
AEPS	1	1	100%		25		25	$0
SCE1	6,240	146	2%	5,438	1,046	19%	152,743	($676,776)

* Results for PGAE and SCE1 include Schedules submitted by other entities through PG&E and SCE as their Schedule Coordinator, respectively. The ISO does not have data to clearly identify which Schedules/Meter Data correspond to Market Participants other then PG&E and SCE.

Similarly, results for the PX (PXC1) were disaggregated by the utility distribution system in which Load ids were located (PG&E, SCE or SDGE). Therefore, these results include Schedules/metering data for these utilities as well as other entities.

Table 3. Overscheduling of Load (January 1, 2000 – June 19, 2001)

ID	Total Number of Hours	Number of Hours where Over Threshold	Pct. Hours Over Threshold	Average Metered Load when Over Threshold	Average MW Overscheduled when Over Threshold	Average Load Deviation % when Over Threshold	Sum of MW Overscheduled when Over Threshold	Total Estimated Uninstr. Energy Payment when Over Threshold
EPMI	12,839	6,016	47%	797	376	47%	2,262,550	$333,027,879
PWRX	7,864	3,969	50%	161	325	201%	1,290,048	$209,248,217
PETP	3,974	3,456	87%		250		862,960	$123,733,109
SCEM	5,859	4,662	80%		188		877,418	$122,094,985
SETC	11,057	4,652	42%	25	175	708%	814,657	$109,444,209
APX1	12,839	5,270	41%	193	161	84%	849,980	$104,136,083
HFET	2,393	2,293	96%		224		512,561	$76,860,873
PGAE *	8,784	1,368	16%	1,039	215	21%	293,820	$33,223,679
CRLP	9,863	3,109	32%	39	81	209%	250,828	$30,250,109
ECH1	12,839	2,450	19%	45	79	174%	192,703	$23,481,764
PGAB / PGAE *	4,055	839	21%	1,352	299	22%	250,731	$16,031,412
NCPA	12,742	1,839	14%	36	60	164%	109,941	$15,915,826
CAPP	12,103	2,186	18%	1	124	12460%	271,225	$14,036,936
PXC5	80	80	100%		1,125		89,999	$12,267,851
NES1	12,839	1,228	10%	0	90	42978%	110,316	$11,147,720
RVSD	12,839	2,657	21%	205	47	23%	125,901	$10,642,658
SRP1	11,616	1,046	9%	437	90	21%	94,372	$8,391,312
APS1	12,839	1,161	9%	131	56	43%	65,027	$7,667,247
PXC1 / SDGE *	9,480	275	3%	1,550	270	17%	74,119	$7,458,904
NEI1	11,999	1,044	9%	459	97	21%	100,767	$7,278,379
ANHM	12,839	1,260	10%	291	67	23%	83,869	$6,594,696
PGES	4,008	1,337	33%	399	128	32%	170,892	$5,477,717
PGEC *	3,623	153	4%	7,785	1,341	17%	205,195	$2,665,302
VERN	12,839	208	2%	133	45	34%	9,434	$1,935,726
WESC	12,481	692	6%	0	67	15270%	46,576	$1,772,323
PSE1	48	48	100%		150		7,200	$1,705,367
PASA	12,839	394	3%	163	37	23%	14,600	$1,539,439
PXC1 / SCE *	11,073	44	0%	6,631	991	15%	43,604	$1,082,724
SCE1 *	12,839	233	2%	3,409	716	21%	166,842	$1,067,834
WAMP	12,839	173	1%	114	33	29%	5,722	$1,028,812
AZUA	12,839	151	1%	39	30	76%	4,496	$750,394
SDG3	3,359	36	1%	1,568	270	17%	9,729	$670,814
LGE1	3,648	208	6%	527	104	20%	21,698	$647,585
COTP	11,012	3	0%		998		2,993	$492,247
PAC1	9,722	32	0%	27	76	279%	2,447	$350,037
SEL1	10,353	49	0%	33	30	92%	1,491	$161,648
IEPI	9,480	173	2%	188	33	17%	5,676	$149,747
PXC1 / PGAE *	10,896	23	0%	7,134	1,221	17%	28,085	$134,307
APX3	3,089	19	1%	47	52	109%	986	$88,712
IPC1	12,839	25	0%	14	31	213%	764	$22,765
EPPS	3	2	67%		68		135	$9,497
SCL1	10,273	1	0%	4	25	696%	25	$756
AEPS	1	1	100%		25		25	$0

* Results for PGAE and SCE1 include Schedules submitted by other entities through PG&E and SCE as their Schedule Coordinator, respectively. The ISO does not have data to clearly identify which Schedules/Meter Data correspond to Market Participants other then PG&E and SCE.

Similarly, results for the PX (PXC1) were disaggregated by the utility distribution system in which Load ids were located (PG&E, SCE or SDGE). Therefore, these results include Schedules/metering data for these utilities as well as other entities

Company Names (for Tables 1 through 3)

ID	NAME
AEPS	American Electric Power Service Corporation
ANHM	City of Anaheim
APS1	Arizona Public Service Company-APS1
APX1	Automated Power Exchange, Inc-APX1
APX3	Automated Power Exchange Inc-APX3
APX4	Automated Power Exchange-APX4
AZUA	City of Azusa
BAN1	City of Banning
CALP	Calpine Energy Services
CAPP	California Polar Power Brokers LLC
CDWR	California Department of Water Resources
CERS	California Department of Water Res.
COTB	CA-OR Transmission Project
COTP	CA-OR Transmission Project
COTP / COTB	CA-OR Transmission Project
CPSC	Constellation Power Source Inc.
CRLP	Coral Power, LLC
DETM	Duke Energy Trading and Marketing, L.L.C.
ECH1	Dynegy Power Marketing, Inc.
EPMI	ENRON Power Marketing Inc
EPPS	El Paso Power Services Company
ESRC	Edison Source
HFET	HAFSLUND ENERGY TRADING L.L.C.
IEPI	Illinova Energy Partners, Inc
IPC1	Idaho Power Company
LGE1	Louisville Gas and Electric Company
NCPA	Northern California Power Agency
NEI1	NewEnergy Inc.
NES1	Reliant Energy Services, Inc.
PAC1	PacificCorp
PAC3	PacifiCorp-Green
PASA	City of Pasadena
PETP	PG&E Energy Trading Power, L.P.
PGAB / PGAE	Pacific Gas and Electric Company
PGAE	Pacific Gas and Electric Company
PGES	PG & E Energy Services
PSE1	Puget Sound Energy
PWRX	British Columbia Power Exchange
PXC1 / PGAE	PX (Pacific Gas & Electric Company Region)
PXC1 / SCE	PX (Southern California Edison Region)
PXC1 / SDGE	PX (San Diego Gas & Electric Region)
PXC3	California Power Exchange 3 - PG&E
PXC3 / PCG1 / PCGB	Pacific Gas and Electric Company
PXC5	California Power Exchange 5
RVSD	City of Riverside
SCE1	Southern California Edison Company
SCEM	Mirant
SCL1	Seattle City Light
SDG3	San Diego Gas & Electric, Merchant
SDG4	San Diego Gas and Electric, Merchant
SDGE	San Diego Gas and Electric Company
SEL1	Strategic Energy, LLC
SETC	Sempra Energy Trading Corporation
SRP1	Salt River Project
VERN	City of Vernon
VSYN	VIASYN, INC
WAMP	Western Area Power Administration
WESC	Williams Energy Marketing and Trading
WRDG	Western Area Power Admin.-Redding

II. Circular Schedules ("Death Star")

The purpose of this report – like previous related reports --- has been to provide an indication of the potential magnitude to which the "Death Star" strategy outlined in the Enron memos may have been employed by Market Participants, and to identify specific Schedules and transactions that could provide a starting point for further investigation and potential legal and regulatory actions related to the practices outlined in the Enron memos. As such, the methodology developed by DMA and the resulting analysis was intentionally designed to "cast a broad net" and to identify all market activity that could be indicative of the "Death Star" strategy. DMA has continued to review and refine its calculation of Congestion revenues earned by import/export Schedules that could potentially be indicative of the "Death Star" trading strategy, as documented in a revised analysis posted on the ISO website on January 17, 2003.[18]

Methodology

The "Death Star" scenario described in the Enron memos is an example of what the ISO refers to as a "circular" Schedule, or a series of Energy Schedules that appear as import and export Schedules through the ISO control area, but actually include additional Schedule(s) outside the ISO control area which form a closed "loop" of scheduled Energy with no specific, physical, beginning (source) or end (sink). Thus, the type of circular Schedule described under the "Death Star" strategy would appear in ISO Scheduling records simply as an import and export from the ISO control area (earning Congestion revenues by creating a counterflow), with the "return" portion of the Schedule being outside the ISO control area.[19]

The potential frequency and financial gains from circular Schedules were analyzed by identifying import/export Schedules (of equal quantities) by the same SC that generated Congestion revenues from counter-flows on inter-ties and/or internal paths within the ISO. This approach may underestimate circular Schedules since the analysis only includes import/export Schedules that can be matched because they are of (approximately) equal quantities by the same SC. For instance, the strategy could also be employed by a single SC using more than two Schedules (e.g. two 50 MW import Schedules on two different ties, paired with a 100 MW export Schedule on a third tie). In addition, it could be employed by two or more SC's (e.g. a 50 MW import Schedule by one SC, coupled with an inter-SC trade to another SC, who then exports all or part of the amount transferred from the other SC). The methodology used in this study does not capture either of these two types of strategies (non-equal capacity and inter-SC trading). At the same time, such matching would also include "non-circular"

[18] Addendum to October 4, 2002 Report on Analysis of Trading and Scheduling Strategies Described in Enron Memos: Revised Results for Analysis of Potential Circular Schedules ("Death Star" Scheduling Strategy) January 17, 2003.

[19] In addition, circular Schedules may be created by "looping" Energy back through the ISO control area under a different SC. However, this particular strategy would typically only be profitable if the Energy schedule in the congested direction is scheduled by an SC with Existing Transmission Rights ("ETR"s), so that no Congestion charges are incurred for this "return" portion of the circular Schedule.

wheeling Schedules (or other combinations of export/import Schedules) which may have a distinct physical source and sink outside the ISO control area.

The analysis of potential circular scheduling in this report is designed to identify all export/import Schedules which may, based on the information available to the ISO, be circular Schedules such as those described under the “Death Star” strategy. This analysis identifies potential circular Schedules based on two basic characteristics of such Schedules that may be detected in ISO data: (1) an import and export of approximately the same amount of Energy by a SC during the same hour, which (2) generate net Congestion payments for the SC due to counterflows created over one or more paths. Thus, while all combinations of import/export Schedules that earn Congestion revenues by creating a counterflow are clearly not circular Schedules, these key characteristics may be used to identify export/import Schedules that may be part of a circular Schedule submitted for purposes of earning Congestion revenues.

There are instances where a single import (export) Schedule will be paired with more than one export (import) Schedule due to the matching algorithm employed in the methodology. Only one of these multiple pairs is simultaneously feasible and the ISO has no means for determining which of these pairs may have been intended by the SC. In the case where multiple pairings are generated by the algorithm, the pair with the highest net gain from Congestion counter-flow payments less any Congestion charges is selected to be included in the final tabulation. This selection is made on returns only and is done specifically to avoid double counting when tabulating the extent to which this strategy was employed and the potential gains that result. The selection of one pair from multiple pairings does not exclude any of the paired schedules that were not selected for inclusion in the final tabulation from the pool of schedules that may have been executed in the manner of the “Death Star” strategy.

Provided below is a more detailed description of this analysis:

1. First, for each SC, the import and export Schedules are matched for the same operating hour submitted by the same SC for approximately the same quantity (within a small tolerance for rounding). This matching is done separately for final Day-Ahead Schedules and final Hour-Ahead Schedules.

2. Congestion payments and charges for each pair of import/export Schedules are then calculated based on the scheduled amount (MW), and the Congestion prices and direction the import/export Schedules would create a scheduled flow on each Congestion path. We then identify Schedules that would be covered under ETC rights, and account for the fact that these Schedules would not pay Congestion charges or earn Congestion revenues for any counter-flows provided. Any pair of Schedules for which one leg of the pair was covered by an ETC is excluded from the final tabulation. For example, for a pair of Schedules representing an 25 MW import into NP15 over COI and a 25 MW export from SP15 on Palo Verde (with no ETC’s on either leg of the pair), Congestion charges/payments would be calculated for a 25 MW flow in the north-to-south direction on COI, Path 15, Path 26 and Palo Verde.

3. For each pair of import/export Schedules, the total net Congestion payments were calculated (taking into account all paths over which a flow would be earned or be charged Congestion charges). Pairs of import/export Schedules resulting in positive net Congestion revenues during any hour (due to counterflow payments in excess of any Congestion charges on other paths) are identified as those that could represent circular schedules submitted in order to earn Congestion revenues.

4. Total Congestion revenues earned by the Schedules identified in Step 3 are summed. In cases where one leg of a circular Schedule was paired with more than one counterpart leg, the pairing that yielded the highest net gain was selected to be included in the tabulation of gains and capacity scheduled under this strategy.

5. Finally, pairs of import/export Schedules representing less than 1 MW and/or $1 in counterflow revenues were screened out of the analysis. These Schedules appear to result from rounding that occurs in the ISO Congestion Congestion Management system.

Table 4. Total Congestion Revenues from Counterflows Created by Import/Export Schedules (Matched by MW Amount)

ID	Company	Pre-refund Period	Refund Period	Total
EESI	Enron Energy Services, Inc.	$1,783,157	$379,328	$2,162,485
CRLP	Coral Power, LLC	$337,982	$1,213,017	$1,550,999
SETC	Sempra Energy Trading Corporation	$348,020	$900,377	$1,248,397
APX	Automated Power Exchange, Inc	$0	$726,099	$726,099
SCEM	Southern Company Energy Marketing, L.P.	$95,419	$9,650	$105,069
DETM	Duke Energy Trading and Marketing, L.L.C.	$10,600	$85,381	$95,981
IPC	Idaho Power Company	$1,980	$81,393	$83,373
AQPC	Aquila Power Corporation	$75,975	$0	$75,975
WESC	Williams Energy Services Corporation	$4,972	$35,115	$40,087
BCHA	British Columbia Power Exchange Corporation	$1,882	$29,574	$31,456
MID	Modesto Irrigation District	$10,059	$4,245	$14,304
SCEC	Southern California Edison Company	$10,200	$1,380	$11,580
PGE	Portland General Electric	$5,750	$0	$5,750
CPCO	Calpine Corporation	$0	$4,376	$4,376
PSE	Puget Sound Energy	$0	$2,982	$2,982
APS	Arizona Public Service Company	$1,174	$0	$1,174
HFET	Hafslund Energy Trading, LLC	$425	$0	$425
		$2,687,595	**$3,472,917**	**$6,160,512**

Note: Includes all import/export combinations by the same SC (matched by MW amount) that earned net Congestion revenues from counterflows on interties and internal ISO paths. The ISO does not have sufficient information to determine if these Schedules represent actual physical sources and sinks that mitigated congestion, or are the type of "circular" Schedule without physical source and sink, such as the Death Star scheme described in the Enron memos.

III. Ancillary Services Buyback ("Get Shorty")

The Enron memo describes two distinct gaming "strategies" in the A/S markets:

1. Taking advantage of systematic differences in the Day-Ahead and Hour-Ahead Market prices for A/S by selling A/S in the Day-Ahead Market and buying them back, when possible, at a lower price in the Hour-Ahead Market.

2. Selling A/S in the Day-Ahead Market from imports for which resources are not actually available (with the intent to "buy back" these A/S in the HourAhead Market at a lower price).

Methodology

Total gains by each SC from selling back Ancillary Services in the Hour-Ahead Market were calculated based on the difference in Day-Ahead/ Hour-Ahead Market prices for each MW sold back by each SC in the Hour-Ahead Market. Any losses from the sellback of A/S capacity at prices that were higher than Day-Ahead prices were included in the analysis to reflect the fact that the "sellback" strategy was not always successful. However, this analysis shows that gains from sellback of A/S far outweigh any losses, suggesting that SCs employing this trading strategy were highly successful at anticipating when the Hour-Ahead Market prices would be lower than the Day-Ahead Market prices.[20]

Results

Table 5 summarizes these results for each SC by time period (pre-refund and refund), in terms of both gross and net gains from sellback of A/S. As noted in the October 4, 2002 Report, the ISO does not have information that could be used to determine the extent to which A/S capacity sold in the Day-Ahead Market and then "sold back" in the Hour-Ahead Market was not actually available or could not have been provided.

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[20] As compared to previous drafts of this report, the "Get Shorty" figures in this report reflect additional filtering to omit transactions with trivial buy-back quantities (<= 1% of DA procurement) and buy-back transactions that may have been initiated by the ISO in response to changes in branch group capacity or a decrease in the maximum amount of A/S that could be purchased from resources outside the control area. In both these cases, the curtailment by the ISO will be *pro rata*, so the same percent cut would apply to all schedules affected on a branch group. To capture these two circumstances, records were omitted if (1a) all DA A/S schedules on that branch group were curtailed in the HA market and (1b) there was more than one DA A/S schedule on that branch group -or- (2) if there were multiple buy-backs on the same branch group with the same percent of capacity purchased back in the HA market. For the entire period from January 1, 2000, through June 21, 2001, imposing these filters on the transactions resulted in a decrease in transactions from 14,275 to 9,421 and a decrease in potential net gains from $47.2 million to $27.8 million.

Table 5: Sellback of Ancillary Services
Pre-refund Period (January 1-October 1, 2000)

ID	Name	Gains	Losses	Net Gains
CRLP	Coral Power LLC	$6,010,809	-$481,212	$5,529,597
MID	Modesto Irrigation District	$4,692,758	-$75,725	$4,617,034
AVEI	Avista Energy Inc	$4,260,564	-$55,176	$4,205,388
SETC	Sempra Energy Trading Corporation	$3,701,719	-$117,636	$3,584,084
BCHA	British Columbia Power Exchange Corporation	$120,569	-$15,076	$105,493
AZUA	City of Azusa	$90,789	-$218	$90,571
GCPD	Grant County PUD	$35,550	-$7,395	$28,155
TCEP	Tuscon Electric Power	$23,679	-$1,713	$21,966
EESI	Enron Energy Services Inc.	$6,383	$0	$6,383
IPC	Idaho Power Company	$2,085	$0	$2,085
VERN	City of Vernon	$1,940	$0	$1,940
LDWP	Los Angeles Water and Power	$15,858	-$52,702	-$36,844

Table 6: Sellback of Ancillary Services
Refund Period (October 2, 2000 – June 21, 2001)

ID	Name	Gains	Losses	Net Gains
EESI	Enron Energy Services Inc.	$4,266,400	-$140,857	$4,125,543
SETC	Sempra Energy Trading Corporation	$3,742,655	-$314,587	$3,428,068
CRLP	Coral Power LLC	$1,479,020	-$30,815	$1,448,205
PSE	Puget Sound Energy	$500,309	-$23,753	$476,556
BCHA	British Columbia Power Exchange Corporation	$271,072	-$213,770	$57,302
AZUA	City of Azusa	$42,800	$0	$42,800
MID	Modesto Irrigation District	$21,714	$0	$21,714
TCEP	Tuscon Electric Power	$16,714	-$110	$16,605
AVEI	Avista Energy Inc	$20,049	-$4,458	$15,591
GLEN	City of Glendale	$12,188	$0	$12,188
IPC	Idaho Power Company	$11,564	$0	$11,564
LDWP	Los Angeles Water and Power	$12,964	-$4,661	$8,304
VERN	City of Vernon	$7,268	$0	$7,268
PSNM	Public Service Company of New Mexico	$869	$0	$869
PASA	City of Pasadena	$29	$0	$28
APX	Automated Power Exchange Inc	$14	$0	$14
BPA	Bonneville Power Administration	$707	-$1,360	-$654

Table 7: Sellback of Ancillary Services (January 1, 2000 – June 21, 2001)

ID	Name	Gains	Losses	Net Gains
SETC	Sempra Energy Trading Corporation	$7,444,374	-$432,222	$7,012,152
CRLP	Coral Power LLC	$7,489,829	-$512,027	$6,977,802
MID	Modesto Irrigation District	$4,714,472	-$75,725	$4,638,747
AVEI	Avista Energy Inc	$4,280,613	-$59,634	$4,220,979
EESI	Enron Energy Services Inc.	$4,272,783	-$140,857	$4,131,926
PSE	Puget Sound Energy	$500,309	-$23,753	$476,556
BCHA	British Columbia Power Exchange Corporation	$391,641	-$228,846	$162,795
AZUA	City of Azusa	$133,589	-$218	$133,371
TCEP	Tuscon Electric Power	$40,393	-$1,823	$38,571
GCPD	Grant County PUD	$35,550	-$7,395	$28,155
IPC	Idaho Power Company	$13,648	$0	$13,648
GLEN	City of Glendale	$12,188	$0	$12,188
VERN	City of Vernon	$9,208	$0	$9,208
PSNM	Public Service Company of New Mexico	$869	$0	$869
PASA	City of Pasadena	$29	$0	$28
APX	Automated Power Exchange Inc	$14	$0	$14
BPA	Bonneville Power Administration	$707	-$1,360	-$654
LDWP	Los Angeles Water and Power	$28,822	-$57,362	-$28,540

Table 8: Net Gains From Sellback of Ancillary Services (January 1, 2000 – June 21, 2001)

ID	Name	Pre-refund Period	Refund Period	Total
SETC	Sempra Energy Trading Corporation	$3,428,068	$3,584,084	$7,012,152
CRLP	Coral Power LLC	$1,448,205	$5,529,597	$6,977,802
MID	Modesto Irrigation District	$21,714	$4,617,034	$4,638,747
AVEI	Avista Energy Inc	$15,591	$4,205,388	$4,220,979
EESI	Enron Energy Services Inc.	$4,125,543	$6,383	$4,131,926
PSE	Puget Sound Energy	$476,556	$0	$476,556
BCHA	British Columbia Power Exchange Corporation	$57,302	$105,493	$162,795
AZUA	City of Azusa	$42,800	$90,571	$133,371
TCEP	Tuscon Electric Power	$16,605	$21,966	$38,571
GCPD	Grant County PUD	$0	$28,155	$28,155
IPC	Idaho Power Company	$11,564	$2,085	$13,648
GLEN	City of Glendale	$12,188	$0	$12,188
VERN	City of Vernon	$7,268	$1,940	$9,208
PSNM	Public Service Company of New Mexico	$869	$0	$869
PASA	City of Pasadena	$28	$0	$28
APX	Automated Power Exchange Inc	$14	$0	$14
BPA	Bonneville Power Administration	-$654	$0	-$654
LDWP	Los Angeles Water and Power	$8,304	-$36,844	-$28,540

IV. Scheduling of Counterflows on Out-of-Service Lines (‘Wheel-Out’)

Background

Another type of scheduling practice identified in the Enron memos is where an SC submits Schedules and/or Adjustment Bids across a tie point that has been de-rated to zero capacity in hopes of getting paid for providing a counter-flow Schedule that will need to be cut by ISO in real time. This practice was apparently referred to as ‘wheel-out’ by Enron traders.

The ISO’s Day-Ahead and Hour-Ahead Congestion Management program (“CONG”) does not currently allow the ISO to reject or cancel Schedules across a tie point that has been de-rated to zero transmission capacity. Instead, when a tie point is de-rated to zero capacity, the ISO sets the available capacity for the tie point in the CONG software to approximately zero.[21] When the CONG software is run, the software adjusts Schedules as necessary to achieve the result of a net zero scheduled flow across the tie point. For example, if Schedules are submitted that create a net flow in one direction, the CONG software will seek to offset this flow by accepting Adjustment Bids for counterflows in the opposite direction and/or reduce initial scheduled flows based on Adjustment Bids).

When a tie point is de-rated, a market notice is sent to Market Participants to notify them of the de-rate. Market Participants also can access forecasts of transmission usage and line and equipment outages that cause de-rating of lines on the ISO’s OASIS system. For an outage or de-rate, they can access the start time, an anticipated end time, and a reason for the outage or de-rate. They also have information on status changes to outages or de-ratings.

With the information available on OASIS and through market notices, SCs have the opportunity to submit a Schedule to provide counter-flow across the tie point or to be adjusted in the direction of the counter-flow (generally in the Hour-Ahead Market) to relieve Congestion on the tie point. In the case where the tie point was de-rated to zero capacity, there will be Congestion in the Hour-Ahead (and Day-Ahead if the duration of the de-rate is long enough) Congestion markets. Any SCs providing counter-flow Schedules to relieve this Congestion are paid counter-flow revenues.

In real-time, when a tie-point is de-rated to zero, the ISO effectively removes this tie-point from the transmission system by canceling all Schedules on the tie-point during the final real time inter-tie checkout just prior to each operating hour. However, any Congestion charges and payments associated with the Day-Ahead and Hour-Ahead

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[21] In practice, the available capacity for lines that are out is set to .03 MW (rather than zero), in order to facilitate computation by the CONG software in a more timely manner.

Congestion Management process described above are not cancelled or reversed from the ISO settlement system.

As noted in the Enron memos, this creates a potential gaming opportunity, in that when a tie point is known to be out of service, an SC may submit Schedules and Adjustment Bids in an effort to create counterflow schedules on tie for which they can earn Congestion revenues, knowing that these Schedules will be cancelled by the ISO in real time. Finally, it should be noted that not all counterflow Schedules on tie lines that are out of service may be attributable to intentional gaming, since an SC may schedule or submit Adjustment Bids on a line prior to notification of the line outage and fail to cancel these after notification of outage occurs.

Methodology

Tie lines that were out-of-service prior to the Day-Ahead and/or Hour-Ahead Congestion Management process were identified by summing up all net final scheduled flows on each time line, and selecting those lines with net final flows of approximately zero.[22] Final counterflow Schedules on out-of-service lines are comprised of Schedules submitted directly by SCs, as well as any adjustments made through CONG.

This set was further screened to include only ties on which Congestion payments/credit occurred, as indicated by a positive Congestion price.

The general formula for calculating the gains from providing counter-flow Schedules across tie points that have been de-rated to zero for any hour is as follows:

$$\text{Counterflow Payment} = MW_{DA} * CC_{DA} + (MW_{HA} - MW_{DA}) * CC_{HA}$$

where

MW_{DA} is the final scheduled MW after the Day-Ahead Congestion Market
MW_{HA} is the final scheduled MW after the Hour-Ahead Congestion Market
CC_{DA} is the Day-Ahead Congestion charge (or credit), and
CC_{HA} is the Hour-Ahead Congestion charge (or credit).

Since schedules that are covered by ETCs neither pay nor receive Congestion revenues, Schedules submitted under ETCs were identified and removed from this stage of the analysis.

Summary results provided in Table 9 of the ISO's October 4, 2002 report included all SCs with gains over $50,000 from counterflow Schedules on out-of-service ties over the

[22] This approach was necessary since the ISO system does not include a database with the historical ratings of each tie-point for each hour that was used in the Congestion Management process. In practice, as noted in the previous footnote, the available capacity for lines that are out of service is set to .03 MW (rather than zero), in order to facilitate computation by the CONG software in a more timely manner.

1998-2002 period covered in that report. (October 4 Report, p. 24). For this report, two modifications have been made which have the effect of changing overall results:

- As with all results in this report, the analysis is limited to the period from January 1, 2000 through June 19, 2001, which is the subject of further investigation by FERC staff.

- In addition, DMA has conducted further review of ISO data in order to determine if the Market Participants' Schedules or Adjustment Bids changed noticeably in a way that would indicate they may have indeed been seeking to exploit the tie line outage in order to earn counterflow revenues for Schedules that they knew would need to be cancelled in real time. For example, Attachment 1 to this report provides a summary of changes that were detected in scheduling and bidding behavior shortly before and during a line outage on the Four Corners branch group on May 27-28, 2000.[23] If no such change was detected in the Market Participants' Schedules and/or Adjustment Bids, the incident was screened from the analysis.

Table 9 provides a summary of this revised analysis.

Table 9. Counterflow Revenues on Out-of-Service Tie Points
January 1, 2000 – June 19, 2001

ID	Name	Pre-Refund Period	Refund Period	Total
ECH1	Dynegy Power Marketing	$1,876,571		$1,876,571
PWRX	British Columbia Power Exchange Corporation	$789,491		$789,491
SETC	Sempra Energy Trading Corporation	$485,895		$485,895
EPMI	Enron Energy Services, Inc.	$225,075		$225,075
CRLP	Coral Power, LLC	$53,938		$53,938
DETM	Duke Energy Trading and Marketing, L.L.C.	$33,558		$33,558
Total		$3,464,528	$0	$3,464,528

Of the $3.465 million in Congestion revenues shown in Table 1 for the pre-refund period, about $3.35 million were gained from a five-hour outage across the Four Corners (FCORNR_5_PSUEDO) tie point within the El Dorado branch group on May 27-28, 2000.

[23] Attachment 1 was previously submitted to FERC in the 100-day discovery process in the Refund Proceeding.

V. Ricochet

As noted in our October 4 report, "ricochet schedules" or "megawatt laundering" refer to a variety of scheduling and trading practices. For this report, we have included analysis of the one general form of "ricochet schedules" or "megawatt laundering": export of power from an SCs resource portfolio within the ISO system on a Day-Ahead or Hour--Ahead basis, and a resale of power back into the ISO system in real time (through either a sale in the ISO Real Time Market or an out-of-market sale). We focus on this specific definition since this can be quantified using ISO records based on the "overlap" between Day-Ahead/Hour-Ahead exports and real time imports by an individual SC during the same hour. As noted in the introduction to this report, the data and methodology employed in this analysis do not identify the extent to which Ricochet or "MW Laundering" may have been employed by two or more SCs, so that Energy may have been exported and then re-imported under two different SC_IDs, since the ISO does not have information to perform such analysis.

Methodology

The analysis identifies, on an hourly basis for each SC, the maximum quantity of Energy that could be exported from within the ISO system on a Day-Ahead or Hour-Ahead basis, and then sold back into the ISO system in real time (through either a sale in the ISO Real Time Market or an out-of-market sale). Specifically, the analysis calculates this based on the lesser of [24]:

(a) the net quantity exported from the ISO control area to the Northwest or Southwest, either through purchases in the PX Day-Ahead Market or through the non-PX portion of the SC's portfolio (physical resources or inter-sc trades); and

(b) the quantity imported into the ISO control area in real-time to the Northwest or Southwest, either through the Imbalance Energy market, or balancing Energy and ex post price ("BEEP") stack, or through out-of-market procurement.

This analysis is performed on a zonal/regional level for each SC to account for the physical constraints associated with moving electricity from the Southwest to the Northwest (or *vice versa*) outside the California ISO control area. For example, potential "Ricochets" from the Southwest are calculated by comparing net exports from the ISO's southern zone (SP15) to control areas bordering the ISO in the Southwest to real time imports to the ISO system from the Southwest. Similarly, potential "Ricochets" from the Northwest are calculated by comparing net exports from the ISO northern zone (NP15) and NOB (the only transmission line connecting SP15 with the Northwest), to real time imports back into the ISO system from the Northwest.

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[24] Specifically, the Energy that can be shifted between these forward and real time markets, or 'laundered', is calculated using the following formula:

MW = Minimum(BEEP_Import + OOM_Import, PX_Net_Exports + Other_Net_Exports).

Results

The results of this analysis are summarized in Table 10, which depicts the total MWs imported as real time Energy that may have been exported in Day-Ahead/Hour-Ahead Schedules by this same SC.

It should be noted that this includes no economic analysis of potential profits from "Ricochet" sales. Analysis of revenues earned from "Ricochet" Schedules could not be completed due to the limited time and data available to DMA. For instance, another way in which Market Participants benefited from ricochet schedules was to collect counterflow revenues for exports scheduled in the Day-Ahead or Hour-Ahead Market when Congestion existed in the import direction. In addition, as previously noted in this report, ricochet Schedules also represent a means of withholding supply from the forward markets (such as the PX Day-Ahead Market) and exercising market power in real time. To the extent that ricochet Schedules were employed to spike prices in California's wholesale markets during one time period, these strategies would have also increased prices in future time periods by increasing the expectation of higher prices. The analyses in this report clearly do not incorporate the overall costs and profits associated with such broader market impacts.[25]

Table 10. Potential Real Time Energy Imports Exported in Day-Ahead/Hour-Ahead Schedules (MW)

ID	Name	Jan 1, 2000 - Oct 1, 2000	Oct 2, 2000 - June 21, 2001	Total (MW)
PSE	Puget Sound Energy	140,304	148,479	288,783
PAC	PacificCorp	132,393	35,537	167,930
APS	Arizona Public Service Company	97,239	12,944	110,183
BCHA	British Columbia Power Exchange Corporation	40,748	58,648	99,396
EESI	Enron Energy Services Inc.	25,388	23,232	48,620
SETC	Sempra Energy Trading Corporation	34,738	6,865	41,603
IPC	Idaho Power Company	0	36,681	36,681
BPA	Bonneville Power Administration	15,879	6,828	22,707
AVEI	Avista Energy Inc	3,592	16,184	19,777
AQPC	Aquila Power Corporation	15,357	0	15,357
SRVP	Salt River Project	8,648	1,858	10,506
LDWP	Los Angeles Water and Power	1,975	7,882	9,857
PGE	Portland General Electric	5,406	4,368	9,775
PSNM	Public Service Company of New Mexico	2,427	25	2,452
WESC	Williams Energy Services Corporation	520	1,380	1,900
GLEN	City of Glendale	0	1,388	1,388
DETM	Duke Energy Trading and Marketing, L.L.C.	0	1,350	1,350
SCEM	Southern Company Energy Marketing, L.P.	673	328	1,001

[25] The summary results presented in Table 10 represent only those Market Participants who showed potential real-time imports from forward export schedules that exceeded 1,000 MW in sum across both time periods.

VI. Scheduling Energy to Collect Congestion Charges ("Cut Counter flows")

A more general type of scheduling practice described in the Enron memos is where SCs submit schedules in the Day-Ahead and/or Hour-Ahead Congestion Markets, providing counter-flows on a congested path. These Schedules receive Congestion charges, which are ultimately paid by SCs with Schedules in the congested direction, as counter-flow revenue in the Day-Ahead and/or Hour-Ahead Congestion Markets. Under current ISO scheduling and settlement practices, SCs may subsequently cut the counter-flow Schedules just prior to real-time, but still receive the counter-flow revenues for Schedules submitted in the Day-Ahead and/or Hour-Ahead Congestion Markets.

This creates a gaming opportunity, in that SCs may earn Congestion revenues for counterflow schedules in the Day-Ahead and Hour-Ahead Markets, and then cancel these Schedules prior to real time. The practice of cutting non-firm Schedules was proscribed by the ISO on July 21, 2000 in accordance with the Market Monitoring and Information Protocol Section of the ISO Tariff and does not appear to have occurred since that time. However, a similar gaming opportunity continued to exist insofar as the same basic strategy could be employed by cutting wheel-through Schedules and/or firm Energy Schedules.

Not all counterflow Schedules cut in real time represent gaming. Wheel through Schedules, for instance, may be cancelled if the SC is unable to the procure Generation and/or transmission to deliver the "import" leg of a wheel through in the ISO system. Similarly, an outage within the ISO system may decrease the overall supply of Energy within an SC's portfolio, and require the cutting of an export Schedule in order to avoid an imbalance in the SC's supply and Demand Schedules. In some cases, the ISO may need to curtail an export due to a de-rate on a tie-line occurring after the Hour-Ahead Congestion Managementarket has ended.[26] However, the logged reason each counterflow Schedule is cut in real time is typically not sufficient to determine the precise reason for the cut, and whether the cut could be due to gaming or not.

Methodology

Total Congestion revenues paid for counterflow Schedules that were cut prior to real time were assessed based on real time Schedule changes made after the Hour-Ahead Market as recorded in the BITS database (used to track any import/export changes made after the close of the Hour-Ahead Market). The analysis included all counterflow Schedules that earned Congestion revenues in the Day-Ahead or Hour-Ahead Markets where the final real time Schedule was <u>less than</u> the final Hour-Ahead Schedule. However, Schedules that were cut due to tie-points being out of service were analyzed separately (see section on "Wheel Out" gaming strategy), and were therefore not included in this analysis.

[26] However, when de-rates occur, the ISO would typically not cut a Schedule that is providing a counterflow on a tie-line, since this would exacerbate Congestion on the de-rated path.

Since Hour-Ahead Schedules may only be partially cut, and may represent a combination of Day-Ahead and Hour-Ahead Congestion revenues, the following two equations were used to calculate the amount of Congestion revenues paid for schedules that were cut in real time.

If the Hour-Ahead Schedule was equal to the Day-Ahead Schedule (so that the SC only earned counterflow revenues in the Day-Ahead Market), the following equation was used:

$$\text{Counterflow Payment} = (MW_{DA} - MW_{RT}) \times CC_{DA}$$

If the Hour-Ahead Schedule was greater than the Day-Ahead schedule (so that the SC may have earned counterflow revenues in both the Day-Ahead and Hour-Ahead markets), the following equation was used:

$$\text{Counterflow Payment} = (MW_{DA} - MW_{RT}) \times CC_{DA} + (MW_{HA} - MW_{DA}) \times CC_{HA}$$

Finally, if the Hour-Ahead Schedule was less than the Day-Ahead schedule (and was subject to the Hour-Ahead Congestion charge for the reduction in its counterflow schedule), the following equation was used:

$$\text{Counterflow Payment} = (MW_{HA} - MW_{RT}) \times CC_{HA}$$

Where:

MW_{DA} is the final scheduled MW after the Day-Ahead Congestion Market
MW_{HA} is the final scheduled MW after the Hour-Ahead Congestion Market
MW_{RT} is the final scheduled MW after the real time checkout process
CC_{DA} is the Day-Ahead Congestion charge (or credit), and
CC_{HA} is the Hour-Ahead Congestion charge (or credit).

DMA also reviewed ISO operating logs for indications of whether each Schedule cut was made by the ISO due to an outage on a tie-point or by the SC for some other reason. Cases where operating logs indicated that the ISO cut the Schedule were screened from the results.

Cut Schedules earning less than $10 in counter flow revenues or less than 1 MW were also excluded from the analysis.

Cut Schedules from Market Participants that provided satisfactory and verifiable explanations for cut Schedules were also removed from the analysis.

Results

Table 11 summarizes the results of this analysis for each SC for the period from January 2000 through June 2001. As shown in Table 11, total Congestion revenues paid for counter flow schedules that were cut in real time identified in this analysis totaled just over $1.4 million over this 18-month period. .

Table 11: Counter-flow Revenues from Cut Schedules Compared by SC

ID	Company	pre_Refund	Refund	Total
MSCG	Morgan Stanley Capital Group		$633,415	$633,415
SETC	Sempra Energy Trading Corporation	$201,671	$198,319	$399,990
CRLP	Coral Power, LLC	$17,356	$95,470	$112,826
EPMI	Enron Energy Services, Inc.	$72,070	$7,428	$79,497
PWRX	British Columbia Power Exchange/Powerex	$28,777	$17,495	$46,273
AEPS	American Electric Power Service Corp	$45,240		$45,240
DETM	Duke Energy Trading and Marketing, L.L.C.		$41,701	$41,701
SCEM	Southern Company Energy Marketing, L.P.		$20,273	$20,273
PSE1	Puget Sound Energy	$17,044	$48	$17,092
ECH1	Dynegy Power Marketing Inc.	$14,980		$14,980
PORT	Portland General Electric	$1,440	$11,257	$12,698
CALP	Calpine Corporation		$4,376	$4,376
EPPS	El Paso Power Services Company		$4,084	$4,084
MID1	Modesto Irrigation District	$2,150		$2,150
IPC	Idaho Power Company		$2,060	$2,060
TEMU	TransAlta Energy Marketing (US)		$1,801	$1,801
WESC	Williams Energy Services Corporation	$609		$609
Total		$401,337	$1,037,728	$1,439,065